U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
PB-281 105

Survey of Flue Gas Desulfurization Systems: Will County Station, Commonwealth Edison Co

PEDCo-Environmental, Inc, Cincinnati, Ohio

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, N C

Mar 78

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/7-78-048b	2.
3. RECIPIENT'S ACCESSION NO. PB281105	
4. TITLE AND SUBTITLE Survey of Flue Gas Desulfurization Systems: Will County Station, Commonwealth Edison Co.	5. REPORT DATE March 1978
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Bernard A. Laseke, Jr.	8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo Environmental, Inc. 11499 Chester Road Cincinnati, Ohio 45246	10. PROGRAM ELEMENT NO. EHE624
	11. CONTRACT/GRANT NO. 68-01-4147, Task 3
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	13. TYPE OF REPORT AND PERIOD COVERED Subtask Final; 1-6/77
	14. SPONSORING AGENCY CODE EPA/600/13

15. SUPPLEMENTARY NOTES IERL-RTP project officer is Norman Kaplan, Mail Drop 61, 919/541-2556. Report EPA-650/2-75-057i gives first survey results.

16. ABSTRACT The report gives results of a second survey of the flue gas desulfurization (FGD) system on Unit 1 of Commonwealth Edison Co.'s Will County Station. The FGD system, started up in February 1972, utilizes a limestone slurry in two parallel scrubbing trains. Each train includes a venturi scrubber, sump, and two-stage sieve tray absorber for the control of fly ash and SO2. The flue gas cleaning wastes are stabilized with lime and collected fly ash and hauled away to an off-site disposal area. The FGD system operated as an SO2-removal unit from February 1972 to July 1977, treating flue gas from the combustion of low sulfur western coal, high sulfur Illinois coal, and blends of both. Experimental SO2-removal operations were concluded in July 1977. The scrubbing system remains in service removing fly ash from low sulfur western coal flue gas. Some SO2 is removed from the flue gas during particulate-removal operations because of the alkalinity of the collected fly ash and the limestone additive used for pH control of the scrubbing solution.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Slurries	Air Pollution Control	13B	11G
Flue Gases	Scrubbers	Stationary Sources	21B	
Desulfurization	Coal	Wet Limestone	07A,07D	21D
Fly Ash	Combustion	Particulate		
Limestone	Cost Engineering			14A
Calcium Oxides	Sulfur Dioxide Dust Control		07B	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 73
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE A04 - A01

EPA Form 2220-1 (9-73)

PB 281 105

EPA U.S. Environmental Protection Agency
Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, North Carolina 27711
EPA-600/7-78-048b
March 1978

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS: WILL COUNTY STATION, COMMONWEALTH EDISON CO.

Interagency
Energy-Environment
Research and Development
Program Report

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EPA-600/7-78-048b
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by

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Contract No. 68-01-4147
Task 3
Program Element No. EHE624

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Research Triangle Park, N.C. 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D.C. 20460

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ACKNOWLEDGMENT

This report was prepared under the direction of Mr. Timothy W. Devitt and Dr. Gerald A. Isaacs. The principal author was Mr. Bernard A. Laseke.

Mr. Norman Kaplan, EPA Project Officer, had primary responsibility within EPA for this project report. Information on plant design and operation was provided by Mr. Rudy Kunshek, Environmental Affairs Department, Commonwealth Edison Company, Bruce R. Mansfield, General Environmental Engineer, Commonwealth Edison Company, and Michael L. Poole, Operating Engineer SO_2 Scrubber, Will County Station, Commonwealth Edison Company.

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SUMMARY

The Commonwealth Edison Company owns and operates the Will County Station on the Chicago Sanitary and Ship Canal, near Romeoville, Illinois. The station consists of four electric power generating units having a total rated capacity of 1147 MW (gross).

Early in 1970 the utility began investigating sulfur removal technology, and the Bechtel Corporation was contracted to assist. The investigation dealt with those processes which, at that time, were sufficiently developed for full-scale installation. Commonwealth Edison consequently decided on a wet scrubbing system using lime or limestone absorbent. Bid Specifications were prepared and bids were received from seven system suppliers. Following a detailed study, a contract for the installation of a limestone scrubbing system on Will County Boiler 1 was awarded to the Babcock and Wilcox Company (B&W).

Boiler 1 is a wet-bottom, coal-fired, radiant cyclone boiler rated at 167 MW (gross). It was manufactured by B&W and went into service in 1955. This unit burns primarily low-sulfur western grade coal (approximately 0.4 percent sulfur); a high-sulfur Illinois grade (approximately 4.0 percent sulfur); or a combination of the two. Design of the Will County scrubber system began in September 1970 and construction started in May 1971. It was completed by February 1972. The main problems were the necessity for a substantial cantilever to backfit the scrubber between the boiler house and service building and the need to complete the job by December 31, 1971.

The system consists of two parallel trains (A-side, B-side), each designed to treat half the boiler flue gas. At present each train contains the following components: two recirculation

tanks, three recirculation pumps, a venturi scrubber, sump, two-stage sieve tray absorber tower, mist eliminator, reheater, and induced draft (I.D.) booster fan. A series of by-pass dampers allows flue gas to be routed around either one or both scrubbing trains while the boiler is in service.

The B-side initially went into service on February 23, 1972, and the A-side on April 7, 1972. Shortly after start-up and during debugging, both modules were plagued with problems. As a result, in May 1973 Commonwealth Edison shut down the B-side, which originally incorporated a turbulent contact absorber (TCA) tower, to concentrate on solving the problems of the A-side, which uses the counter-current tray absorber.

When improved system performance of the A-side was achieved (69 percent operability* for 1974), the utility modified the B-side, incorporating all changes made to the A-side. Major modifications included: removal of the TCA mobile bed packing and its replacement with two stages of sieve trays; a double-stage reinforced mist eliminator in place of the original single-stage unit; and replacement of the reheat tubes in the reheat bundles from 304 stainless steel and corten steel components to 316L stainless steel and carbon steel components. The B-side went back into service May 20, 1975.

In 1976, Commonwealth Edison considered converting the A-side sieve tray absorber to a TCA tower in an effort to improve system operations at Will County while gaining experience for the design, erection, and operation of a 450-MW TCA scrubbing system being supplied by Universal Oil Products and scheduled for operation on Powerton Unit 5, Boiler 51, in December 1979. The shortage of time for data acquisition before the scheduled start-up of the Powerton FGD system prevented this modification from being made.

In July 1977, Commonwealth Edison officially concluded

* Operability index: The number of hours the FGD system is in operation for a given period, divided by the number of boiler hours in the period, expressed as a percentage.

sulfur dioxide removal operations at the Will County No. 1 limestone scrubbing system. Compliance with existing sulfur dioxide emission regulations is being achieved by burning exclusively low-sulfur western coal. Scrubbing operations are continuing in the particulate removal mode, by means of which fly ash is scrubbed from the flue gas with a dilute limestone slurry. The limestone is used for pH control only, preventing potential excursions of the solution into the low pH range, which could cause severe acid corrosion damage. Since the scrubbing solution retains some alkalinity as a result of the addition of limestone, sulfur dioxide removal still occurs, though at a diminished level. Actual removal values have not yet been determined.

The estimated capital and 1975 annual operating costs for the FGD system on Will County Unit 1 are equivalent to $113/kW (including $5/kW for sludge treatment) and 13.06 mills/kWh respectively. These figures represent the cost of a difficult retrofit application, where scrubbers were installed in an extremely congested space and under a construction schedule that required large overtime expenditures. Operating costs are based on a 1975 capacity factor of 49.5 percent.

Summary data on the Will County FGD system are given in Table 1.

Table 1. SUMMARY DATA,

WILL COUNTY UNIT 1 FGD SYSTEM

Unit rating, MW, gross	167
Unit rating, MW, net	144
Fuel	Coal
Annual average (1975)	
Heating value, kJ/kg (Btu/lb)	22,260 (9,570)
Sulfur, percent	1.5
Ash, percent	7.4
FGD system supplier	Babcock & Wilcox
FGD process	Wet limestone scrubbing
FGD trains	2
Start-up date	
A-side	February 1972
B-side	April 1972
Design guaranteed removal efficiency, percent	
Particulates	98
Sulfur dioxide	76
Makeup water	Not available
Sludge disposal	Stabilized sludge hauled to off-site landfill
Economics	
Capital cost (1975)	$113/kW (net)
Annual cost (1975)	13 mills/kWh

SECTION 1

INTRODUCTION

The Industrial Environmental Research Laboratory (IERL) of the U.S. Environmental Protection Agency (EPA) has initiated a study of the performance characteristics and reliability of flue gas desulfurization (FGD) systems operating on coal-fired utility boilers in the United States.

This report, one of a series dealing with such systems, describes a wet limestone scrubbing process developed by Babcock & Wilcox (B&W) and installed at the Will County Station of the Commonwealth Edison Company. It addresses key process design and operating parameters, major start-up and operational problems encountered at the facility and measures taken to alleviate them, and the total installed and annual operating costs. The report is based on information obtained during plant visits on June 28, 1974; June 22, 1976; and June 1, 1977. The information is current as of November 1977.

Section 2 presents data and information on the plant environs and plant facilities. Section 3 provides a detailed description of the FGD system, including process design and process chemistry features. Section 4 analyzes the performance of the FGD system since start-up in 1972. It documents sulfur dioxide and particulate matter removal efficiencies, system dependability, mechanical and chemical problems and solutions, and system economics. Appendix A is the completed plant survey form.

SECTION 2
FACILITY DESCRIPTION

Will County Station of the Commonwealth Edison Company is on the Chicago Sanitary and Ship Canal in Will County, near the town of Romeoville, (1970 population: 12,674*) Illinois. The area contains many large refineries and chemical plants. Canal traffic consists mainly of bulk cargo barges, and it is by this means that coal and limestone are delivered to the Will County Station.

Will County Station has four electric power generating units with a total rated capacity of 1147 MW. Only Boiler 1, a wet-bottom, coal-fired boiler rated at 167 MW, is retrofitted with an FGD system. It was manufactured by B&W and installed in 1955.

Boiler 1 burned a low-sulfur Montana coal, a high-sulfur Illinois coal, or combinations of both during the Will County FGD demonstration program. The average characteristics of these coals are given in Table 2.

The boiler is fitted with an electrostatic precipitator (ESP) manufactured by the Western Precipitation Division of the Joy Manufacturing Company. The ESP has a design particulate collection efficiency of 90 percent and a 79 percent actual particulate collection efficiency on high-sulfur Illinois coal.† It provides primary particulate removal and is currently operated on a full-time basis, independent of FGD operation.

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* State of Illinois Official Road Map (1970 Census) lists 15,336. Rand-McNally Road Map lists 12,674 (1970 est.).

† Collection efficiency of the precipitator depends on fuel supply. The 79 percent efficiency is based on tests conducted June 3, 1975, and June 4, 1975, with coal averaging 3.98 percent in sulfur.

Table 2. CHARACTERISTICS OF COAL FIRED IN WILL COUNTY BOILER 1

Source	Characteristics	Value
Montana	Heating value, kJ/k2	21,167 - 22,330
	Btu/lb	9,100 - 9,600
	Sulfur, percent	0.3 - 0.6
	Ash, percent	3.0 - 6.0
Illinois	Heating value, kJ/kg	22,097 - 24,423
	Btu/lb	9,500 - 10,500
	Sulfur, percent	3.5 - 4.5
	Ash, percent	12.0 - 16.0

The maximum particulate emission allowed under Illinois Pollution Control Board Regulation No. 203(g)(1)(C), effective May 30, 1975, is 86 ng/J (0.2 lb/million Btu).* Using high-sulfur Illinois coal, particulate emission rate from the FGD system is equivalent to 34.4 ng/J (0.08 lb/million Btu).†

Sulfur dioxide emissions are limited by Illinois Pollution Control Board Regulation No. 204(C)(1)(A).* Under this regulation, effective May 30, 1975, the maximum allowable sulfur dioxide emission rate is 774 ng/J (1.8 lb/million Btu). The present sulfur dioxide emission rate, based on 89.2 percent removal efficiency and coal with a sulfur content of 3.8 percent, was measured at 300 ng/J (0.7 lb/million Btu).†† Table 3 presents plant and emission rate data.

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* IPCB Regulations 203(g)(1)(C) and 204(C)(1)(A) were invalidated by Illinois Supreme Court January 20, 1976.

† Rate based on tests conducted June 3, 1975, and June 4, 1975, with coal averaging 3.98 percent sulfur.

†† Rate based on tests conducted September 28, 1976.

Table 3. DESIGN, OPERATION, AND EMISSIONS,

WILL COUNTY UNIT 1

Total rated generating capacity, MW	167
Boiler manufacturer	Babcock & Wilcox
Year placed in service	1955
Unit heat rate, (1975) kJ/net kWh (Btu/net kWh)	11,835 (11,217)
Unit capacity factor, percent (1975)	49.5
Maximum coal consumption rate, kg/sec (short tons/hr)	21.4 (85)
Maximum heat input, GJ/hr (10^6 Btu/hr)	1,688 (1,600)
Served by stack No.	1
Stack height above grade, meters (feet)	107 (350)
Design maximum flue gas rate, m^3/sec @ 179°C (acfm @ 355°F)	363 (770,000)
Emission controls:	
Particulate	ESP and venturi scrubbers
Sulfur dioxide	Venturi scrubbers and sieve tray absorbers
Particulate emission rates:	
Allowable, ng/J (lb/10^6 Btu)	86.0 (0.2)[a]
Actual, ng/J (lb/10^6 Btu)	34.4 (0.08)[b]
Sulfur dioxide emission rates:	
Allowable, ng/J (lb/10^6 Btu)	774 (1.8)[a]
Actual, ng/J (lb/10^6 Btu)	300 (0.7)[c]

[a] IPCB regulations 203(g)(1)(C) and 204(C)(1)(A) were invalidated by Illinois Supreme Court January 20, 1976.

[b] Based on tests conducted June 3, 1975 and June 4, 1975.

[c] Based on tested FGD removal efficiency of 89.2 percent for coal with a sulfur content of 3.8 percent (tests conducted September 28, 1976).

SECTION 3
FLUE GAS DESULFURIZATION SYSTEM

PROCESS DESCRIPTION

The wet limestone scrubbing system designed and installed by B&W on Will County Boiler 1 is guaranteed to remove 98 percent of particulate matter and 76 percent of sulfur dioxide. Removal efficiency values are based on inlet loading conditions of 3.1 g/m^3 (1.355 gr/scf) at 21°C (70°F) while burning Illinois coal, with a sulfur content of 4 percent.

The wet limestone scrubbing system backfitted on the boiler includes a limestone handling and milling system, a sludge disposal system, and two parallel scrubber-absorber trains, each designed to treat half the boiler flue gas. The B-side scrubbing train went into commercial service February 23, 1972, and the A-side scrubbing train on April 7, 1972. Many problems were encountered, which resulted in numerous system modifications. These are discussed in detail in Section 4. The Will County wet scrubber system is described in terms of three basic operations: (1) limestone handling and milling, (2) wet scrubber and absorber trains, and (3) sludge handling and disposal.

Limestone Handling and Milling

Figure 1 depicts the limestone handling and milling facility at Will County Station. It handles limestone used for both scrubbing trains and includes a rock conveyor, two storage silos, two wet ball mills, one slurry storage tank, and two slurry feed pumps.

The limestone, a coarse-ground form about 2 cm (0.75 in.) or less in diameter, is purchased from Rigsby and Barnum Company, and arrives by river barge. It is unloaded at Will County by

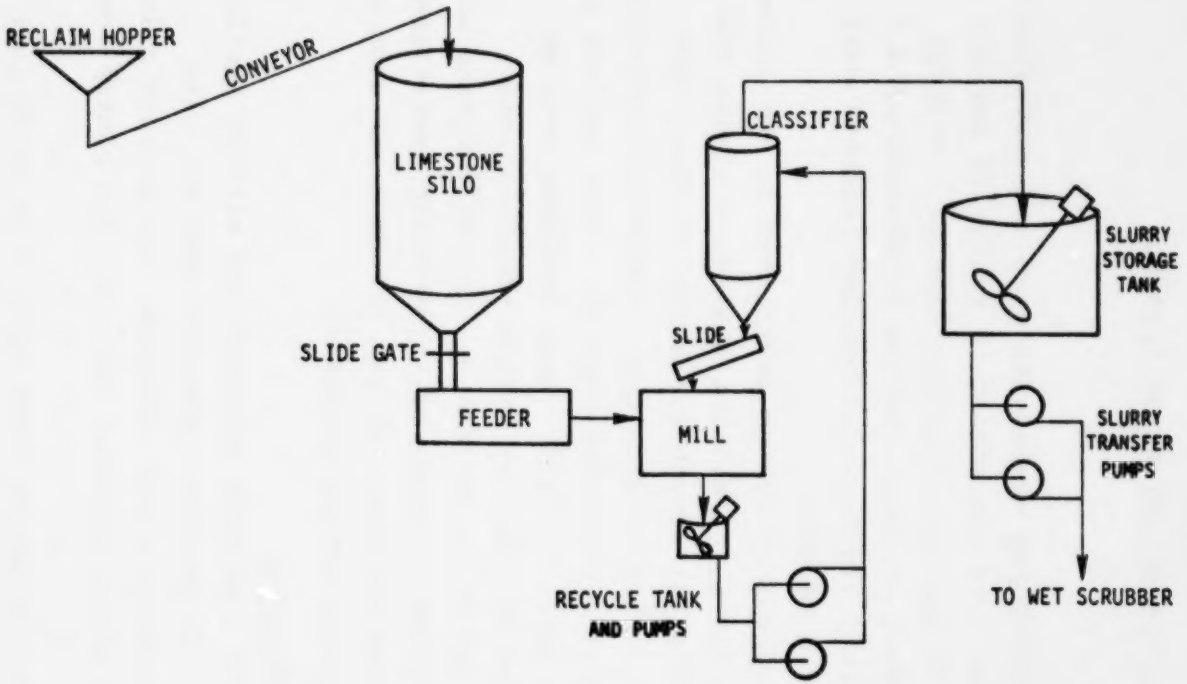

Figure 1. Limestone handling and milling facilities, Will County Station.

coal-handling equipment and transferred by conveyor to two 236-Mg (260-ton) silos. The storage capacity of the silos meets the limestone requirements of FGD operation at full load.

Each storage silo discharges onto a gravimetric feeder that supplies one of two full-size wet ball mill and classification systems. Each system can grind limestone at a rate of 3 kg/sec (12 ton/hr) to a fineness of 95 percent minus 325 mesh. The chemical specifications required allow a minimum calcium carbonate content of 97 percent and magnesium and silica contents of less than 1.0 and 0.5 percent respectively.

The wet ball mills discharge a limestone slurry containing 25 to 30 percent solids to a storage tank. This tank, which has a liquid capacity of 236,588 l (62,500 gal.), is agitated continuously. It was designed to retain the slurry 4 hours before it is pumped to the scrubbing system. The entire limestone milling facility was designed so that one wet ball mill could supply limestone slurry for both scrubbing trains at full-load flue gas capacity.

Wet Scrubber and Absorber Trains

The wet scrubber-absorber system is composed of two identical parallel scrubbing trains, referred to above as the A-side and the B-side. Each train was designed to treat approximately 50 percent of the flue gas, or 182 m^3/sec (385,000 cfm) at 179°C (355°F). The flow of flue gas and solutions through the scrubbing system is illustrated in Figure 2 and described below.

Flue gas emerges from the boiler and passes through an existing ESP (Western, 90 percent design removal efficiency) where primary particulate removal takes place. A by-pass damper, installed downstream from the ESP, permits the gas to by-pass either scrubbing train, or both. The flue gas then enters the scrubbing system through a venturi, where it is contacted with jets of scrubbing slurry sprayed countercurrently from high-pressure nozzles on each side of the rectangular venturi throat. Flue gas velocity and particulate removal are maintained at

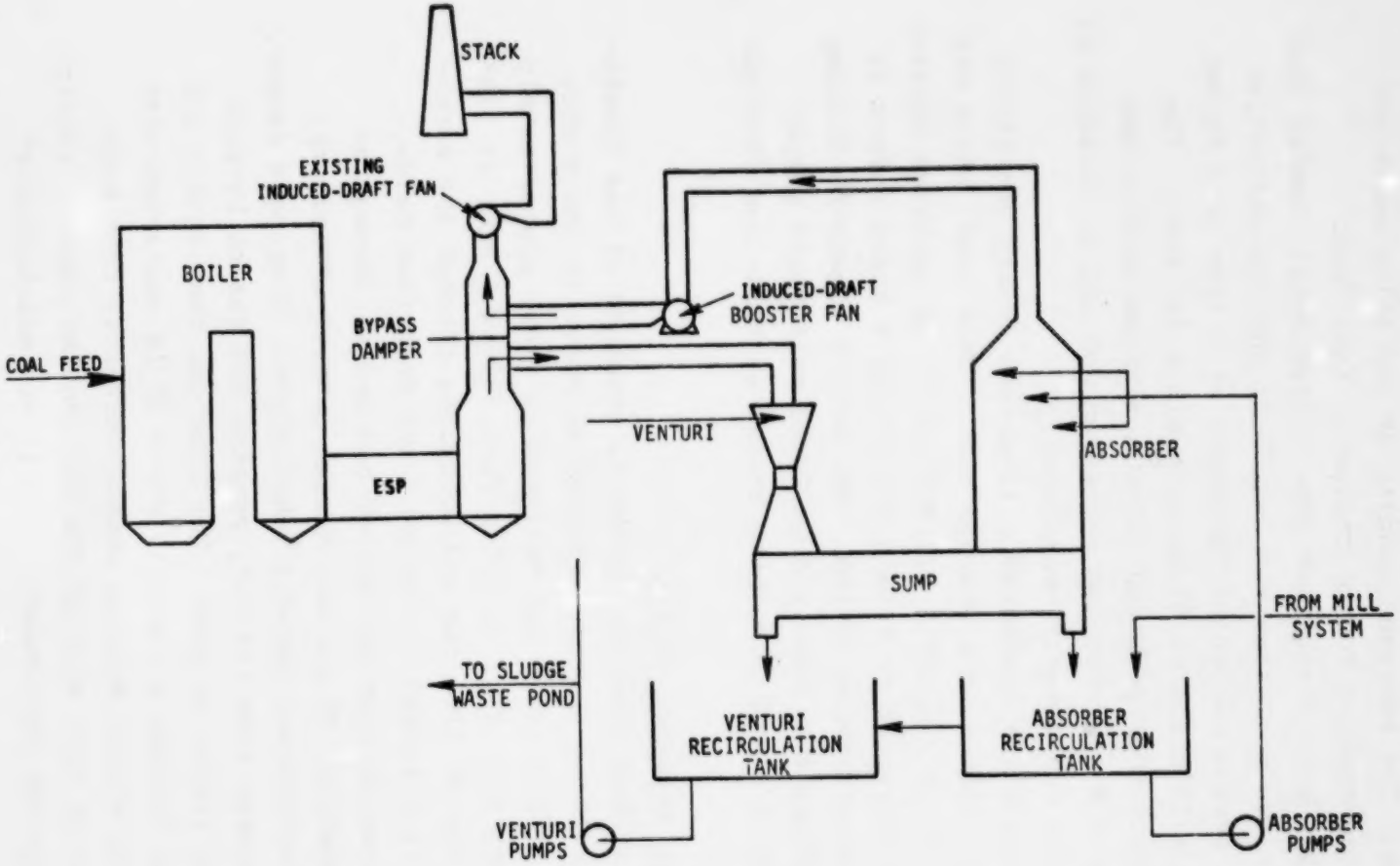

Figure 2. Flow diagram of Will County Boiler 1 and FGD system.

37 m/sec (120 ft/sec) and 94.3 percent respectively, by regulating the pressure drop across the throat at 2.2 kPa (9 in. H_2O).

Quenched flue gas and slurry droplets pass through the sump, where the large gas velocity reduction causes the droplets to leave the flue gas stream. The gas then flows upward through the sulfur dioxide absorber tower at the greatly reduced superficial gas velocity of 3 m/sec (10 ft/sec). The A-side and Bside absorber towers contain two sieve trays wetted by limestone slurry sprays above the trays. The trays provide an extended wetted surface for absorption of the sulfur dioxide from the flue gas by circulated slurry. Pressure drop through the absorption section of each module at full-load conditions is 2.5 kPa (10 in. H_2O).

The cleaned flue gas then continues upward through a mist eliminator (Z-shaped, two-stage, three-pass, chevron-type). Fine mist droplets coalesce on the surface of the mist eliminator, which is equipped with two sets of wash water headers. The lower stage is washed continuously by an underspray of 7.9 l/sec (125 gal./min) of fresh water and intermittently by an overspray of 63.1 l/sec (1,000 gal./min) of pond water for 90 seconds every hour. The scrubbed gas then enters the reheater unit, where its temperature is raised from 53°C to 82°C (128°F to 180°F). Reheat is necessary to prevent condensation in the fans, ducts, and the existing brick-lined stack. The reheat also makes the plume buoyant and thus reduces its visibility.

Each bare tube reheater has nine sections. The bottom three sections of both the A-side and the B-side units are made of 316 L stainless steel, and the remaining six sections are of carbon steel. Each reheater also has four soot blowers. Heat is supplied by saturated steam from the boiler at 2,515 kPa (350 psig) and 252°C (485°F). Condensate from the reheater is returned to the steam circuit at the deaerator heater. An additional temperature boost of approximately 11°C (20°F) from 82°C (180°F) to 93°C (200°F) is provided by the fans.

To compensate for draft loss across the two scrubbing trains, two 1,679-kW (2,250-hp) I.D. booster fans, one per train, were installed at the suction side of the existing boiler I.D. fans.

Both scrubbing trains have two recirculation tanks, each with a capacity of 151 kl (40,000 gal.). One services the venturi scrubber, the other the absorber. Spent scrubbing slurry is discharged from the venturi recirculation loop. The two tanks are tied together in such a way that spent liquor from the absorber recirculation tank flows into the venturi circulation tank. All tanks are fitted with an agitator and pumps. The slurry recirculation rate to the absorber is approximately 649 l/sec (11,000 gal./min), equalling a liquid-to-gas ratio (L/G) of 5 l/m^3 (35 gal./1,000 ft^3) of gas at 49°C (120°F). The liquid recirculation rate to the venturi is 366 l/sec (5,800 gal./min), an L/G of approximately 2.5 l/m^3 (18 gal./1,000 ft^3) of gas at 52°C (125°F).

Sludge Handling and Disposal

Figure 3 illustrates the present scrubbing wastes handling and disposal system employed at the Will County Station. Wastes are discharged from the A-side and B-side venturi recirculation loops either to a 65-diameter thickener or directly to the sludge waste pond. The latter mode is used only in emergencies, or when the thickener is out of service. Clarified water is returned to the process for use in the scrubbing and milling systems.

Thickener underflow or retrieved ponded sludge is stabilized with fly ash and lime and hauled in concrete mixing trucks to an off-site disposal area. Stabilization is achieved at a ratio of 181 kg (400 lb) of fly ash and 91 kg (200 lb) of lime per 0.9 Mg (ton) of dry solids of sludge.

Tables 4 through 8 summarize operating data, design parameters, and design specifications for the major unit operations of the Will County Boiler 1 FGD scrubbing system.

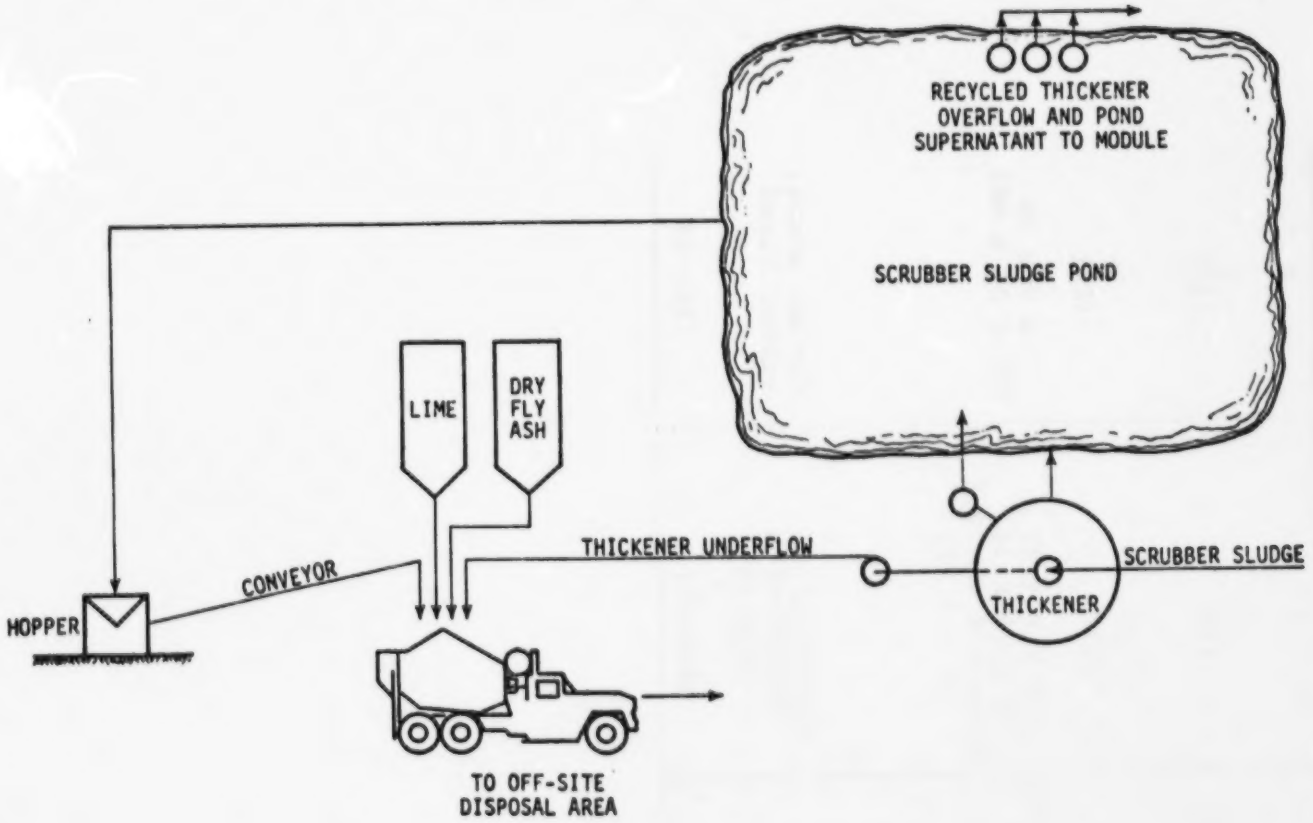

Figure 3. Sludge stabilization and disposal facilities, Will County FGD system.

Table 4. SUMMARY OF DESIGN DATA, SCRUBBING TRAINS

Item	Venturi scrubber	SO_2 absorber tower
Number	2	2
L/G ratio, l/m^3 (gal./1000 acf)	2.5 (18)	5 (35)
Superficial gas velocity, m/sec (ft/sec)	37 (120)	3 (10)
Equipment size, m (ft)	2.5 x 8 x 15 (8 x 26 x 16) [throat 6.4 x 0.5 (21 x 1.8)]	5 x 7 x 18 (16 x 24 x 60)
Material of construction		
Shell	Carbon steel coated with plasite	Corten steel, rubber lined
Internals	Kaocrete	316L SS

Table 5. SUMMARY OF DESIGN AND OPERATING DATA, MIST ELIMINATORS

Number	2
Type	Chevron
Shape	Z-shape, 90° sharp-angle bends
Material of construction	FRP (Hetron)
Number of stages	2
Number of passes	3
Distance between stages, m (ft)	1.2 (4)
Spacing between vanes, cm (in.)	3.8 (1.5)
Pressure drop, kPa (in. H_2O)	0.25 (1.0)
Configuration	Horizontal
Wash system:	
Type	Fresh water underspray/ pond return overspray for first stage; second stage not washed.
Duration	Underspray - continuous; overspray - intermittent
Rate	Underspray - 7 to 8 l/sec (113 to 126 gal./min); overspray - 63 l/sec (1000 gal./min) for 40 sec for each module per hour of operation.

Table 6. SUMMARY OF DESIGN AND OPERATING DATA, REHEATERS

Number	2
Type	Steam in-line reheat
Flue gas reheat:	
Flow rate, m^3/sec (acfm)	179 (380,000)
Temperature, °C (°F)	53 (128)
SO_2 Concentration, ppm (average)	500
Design:	
Number of tube banks	3, 9 rows per bank
Tube size	1.6 cm (0.62 in.) O.D., bare tube
Material of construction	316L SS and carbon steel
Soot blowing	Every 4 hours
Heating medium:	
Pressure, kPa (psig)	2,515 (350)
Temperature, °C (°F)	252 (485)
Consumption rate, kg/sec (lb/hr)	6 (50,000)
Outlet gas temperature, °C (°F)	71 (160)
Energy consumption, % of boiler input	3.2

Table 7. SUMMARY OF DESIGN DATA, RECIRCULATION AND MAKEUP TANKS

Item	Venturi scrubber recirculation tank	SO_2 absorber tower recirculation tank	Limestone slurry makeup tank
Total number of tanks	2	2	1
Retention time at full load	Variable*	Variable†	4 hr
Temperature, °C (°F)	53 (128)	53 (128)	Ambient
pH	5.1-5.7	5.8	7.0
Solids content, percent	8	8	15-30
Specific gravity	1.102	1.049	
Material of construction	Rubber-lined carbon steel	Rubber-lined carbon steel	Carbon steel

Table 8. DESIGN PRESSURE DROP FOR EACH SCRUBBING TRAIN

[kPa (in. H_2O)]

Venturi scrubber	2.2 (9)
Sieve tray absorber	2.5 (10)
Mist eliminator	0.25 (1)
Reheater	1.5 (6)
Ductwork	0.75 (3)
Total FGD system	7.20 (29)

* Design value is 8 minutes. Different rates were used on an experimental basis during the course of the SO_2 program.

† Design value is 4 minutes. Different rates were used on an experimental basis during the course of the SO_2 program.

PROCESS CHEMISTRY: PRINCIPAL REACTIONS

The chemistry involved in the wet limestone scrubbing process is complex, and a detailed account is beyond the scope of this discussion. The principal steps involved in this process, however, are discussed as follows:

Initially, the sulfur dioxide must diffuse from the gas phase into the liquid phase

$$SO_2 \uparrow \rightleftharpoons SO_2 \text{ (aq.)}$$

The sulfur dioxide dissolved in the aqueous phase next undergoes hydrolysis and ionization, yielding sulfurous acid, bisulfite, sulfite, and hydrogen ions

$$SO_2 \text{ (aq.)} + H_2O \rightleftharpoons H_2SO_3$$
$$H_2SO_3 \rightleftharpoons H^+ + HSO_3^-$$
$$HSO_3^- \rightleftharpoons H^+ + SO_3^=$$

In addition to the formation and subsequent ionization of sulfurous acid, some of the sulfur dioxide reacts with oxygen in the gas phase to yield sulfuric acid, bisulfate, sulfate, and hydrogen ions.

$$2SO_2 \uparrow + O_2 \uparrow \rightleftharpoons 2SO_3 \uparrow$$
$$SO_3 \uparrow + H_2O \rightleftharpoons H_2SO_4$$
$$SO_2 \text{ (aq.)} + O_2 \text{ (aq.)} + H_2O \rightleftharpoons H_2SO_4$$
$$H_2SO_4 \rightleftharpoons H^+ + HSO_4^-$$
$$HSO_4^- \rightleftharpoons H^+ + SO_4^=$$

Analagous to the gas-phase oxidation steps discussed above, the sulfite ion undergoes oxidation by dissolved oxygen present in the scrubbing solution and forms a sulfate ion according to the following reaction:

$$2SO_2^= + O_2 \rightleftharpoons 2SO_4^=$$

The dissolution and ionization of the limestone additive into an acidic medium yields the ionic species of calcium, carbonate, bicarbonate, and calcium bicarbonate.

$$CaCO_3 \downarrow \rightleftharpoons CaCO_3\ (aq.)$$

$$CaCO_3\ (aq.) \rightleftharpoons Ca^{++} + CO_3^{=}$$

$$Ca^{++} + H^{+} + CO_3^{=} \rightleftharpoons CaHCO_3^{+}$$

$$CaHCO_3^{+} \rightleftharpoons Ca^{++} + HCO_3^{-}$$

The calcium ions react with the sulfite and sulfate ions in the aqueous phase, resulting in the formation and precipitation of calcium sulfite and calcium sulfate salts.

$$Ca^{++} + SO_3^{=} \rightleftharpoons CaSO_3$$

$$CaSO_3 + 1/2\ H_2O \rightleftharpoons CaSO_3 \cdot 1/2\ H_2O \downarrow$$

$$Ca^{++} + SO_4^{=} \rightleftharpoons CaSO_4$$

$$CaSO_4 + 2\ H_2O \rightleftharpoons CaSO_4 \cdot 2\ H_2O \downarrow$$

PROCESS CONTROL

Figure 4 is a diagram of the instrumentation and controls for the scrubber-absorber train portion of the Will County FGD system. The controls are designed to maintain optimum operating efficiency by monitoring the following process variables: pressure drop across the venturi throat, limestone feed, and scrubbing solution pH. Monitoring and control are performed automatically from the scrubber control room panel in the boiler control room.

Gas loading

The modulation of the gas flow through the scrubbing system is controlled as a function of boiler load variation. This is accomplished automatically by a boiler load signal, which controls the I.D. fan speed and booster fan dampers.

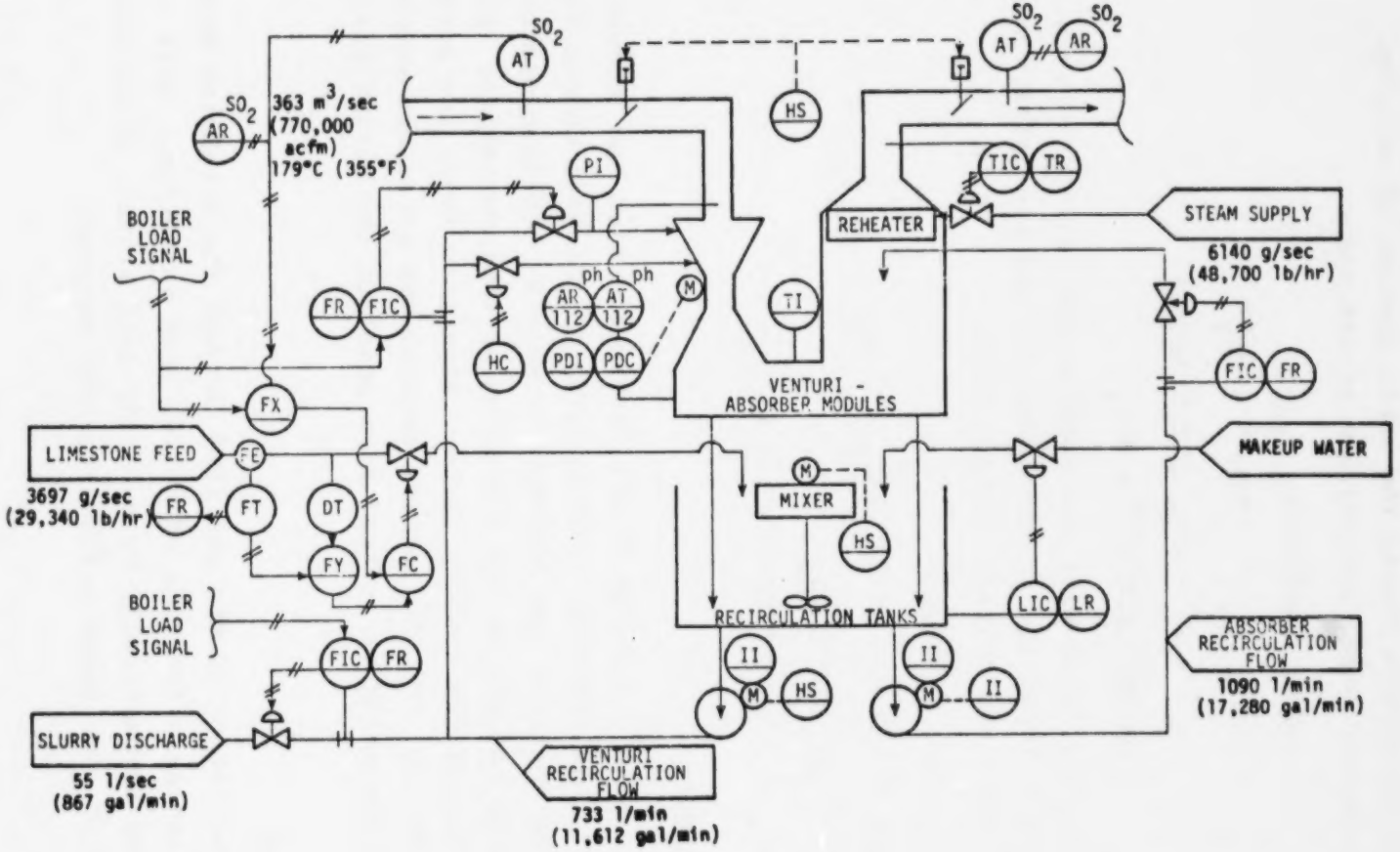

Figure 4. Instrumentation and control diagram, Will County FGD Modules.

Pressure drop across the venturi

Particulate removal efficiency and superficial gas velocity in the scrubbing system are regulated by controlling the pressure drop across the venturi throat. A constant value of 2.2 kPa (9 in. H_2O) is maintained by a differential pressure controller and pressure indicator network installed on the venturi throat. This network is in turn connected to the throat-drive motor, which expands or contracts the throat opening.

Limestone slurry feed

The limestone slurry feed to the scrubbing system is controlled by monitoring the scrubbing solution pH at the venturi inlet. The pH control range is variable. When the pH drops below or exceeds the control range, the feed rate of fresh limestone slurry is increased or decreased to the scrubbing system by opening or closing the feed valves.

Spent slurry discharge

Spent scrubbing slurry is discharged from the scrubbing system off the venturi recirculation line and transported to the thickener. The amount of waste blowdown is regulated by a level controller. This controller works in conjunction with a flow control valve, which is opened and closed as a function of the liquid level in the venturi recirculation tank.

Sulfur dioxide level

The concentration of the sulfur dioxide species in the flue gas is checked periodically by wet chemical techniques.

SECTION 4
FGD SYSTEM PERFORMANCE

PERFORMANCE TEST PROGRAMS

Three performance test runs have been conducted on the Will County FGD system. Babcock & Wilcox conducted a series of preliminary performance tests in May, and during July and August, 1972, and the utility itself did tests during a high-sulfur coal burn program in May 1975, and September 1976.

Table 9 summarizes the results of the May 1972 test program. Outlet particulate loading during the test varied from 0.0167 to 0.0764 g/m^3 (0.0073 to 0.0334 gr/scf). The design guarantee value was 0.0568 g/m^3 (0.0248 gr/scf). Sulfur dioxide removal efficiency and resulting outlet values were not applicable to the design guarantee because a varying blend of low-sulfur western coal and high-sulfur Illinois coal was burned. During normal operating conditions, sulfur dioxide removal efficiency was about 80 percent. It dropped to 67 percent when the limestone slurry feed to the scrubbing system was deliberately reduced.

During the July-August 1972 test period, the system treated flue gas from the combustion of high-sulfur Illinois coal (the design coal). Outlet particulate loading varied from 0.0487 to 0.0636 g/m^3 (0.0213 to 0.0278 gr/scf). Sulfur dioxide removal efficiency varied from 67 to 94 percent. As in the May 1972 test period, all the runs were made on the A-side with the ESP unit de-energized. Tables 10 and 11 summarize the results.

A high-sulfur burn test program was initiated by the utility in May 1975, during which sulfur dioxide removal, particulate removal in the scrubber, and ESP removal efficiencies were measured and the process chemistry was monitored. Removal effi-

Table 9. PRELIMINARY TEST DATA, A-SIDE SCRUBBING TRAIN

MAY 18 TO 23, 1972

Test number	1	2	3	4	5	6	7	8	9	10	11	12
Date	5-18	5-18	5-19	5-19	5-20	5-20	5-21	5-21	5-22	5-22	5-23	5-23
Load, MW	113	113	114	115	111	112	113	115	110	111		58
Gas flow, m^3/sec (acfm x 10^3)	158 (335)	168 (355)	158 (335)	160 (340)	158 (335)	151 (320)	149 (315)	146 (310)	149 (315)	158 (335)	97 (205)	101 (215)
Scrubber system, pressure drop, kPa (in. H_2O)	6.1 (24.5)	7.2 (29)	5.2 (21)	6.2 (25)	6.0 (24)	6.3 (25.5)	5.6 (22.5)	5.5 (22.0)	5.8 (23.2)	5.7 (23.0)	4.0 (16.0)	4.5 (18.0)
Dust inlet, g/m^3 (gr/dscf)		0.216 (0.0944)	0.330 (0.1440)	0.336 (0.1470)	0.253 (0.1105)	0.410 (0.1790)			0.700 (0.3060)	0.590 (0.2580)		
Dust outlet, g/m^3 (gr/dscf)	0.0531 (0.0232)	0.0181 (0.0079)	0.0167 (0.0073)	0.0682 (0.0298)	0.0597 (0.0261)	0.0584 (0.0255)			0.0469 (0.0205)	0.0764 (0.0334)		
SO_2 inlet, ppm	1145	1140	890	930	1130	1000	640	910	1000	545	1200	1150
SO_2 outlet, ppm	67	75	294	35	285	118	18	45	223	180	45	50
SO_2 removal efficiency, %	94	93	67	96	75	88	97	95	81	67	95	96
Absorber slurry solids concentration, %	3.4	5.2	5.5	5.2	2.5	4.3	5.0		2.9	2.2		1.5
Absorber pH	6.5	6.3	7.4	6.3	5.7	5.8	7.2	5.7	5.9	5.4	6.1	6.1

Table 10. PRELIMINARY TEST DATA, A-SIDE SCRUBBING TRAIN

JULY 25 TO AUGUST 7, 1972

Test number	1	2	3	4	5	6
Date	7-25	7-26	7-27	8-4	8-4	8-7
Load, MW	102	100	112	104	103	98
Gas flow, m^3/sec (acfm x 10^3)	154 (326)	130 (276)	172 (364)	181 (383)	181 (383)	189 (400)
Scrubber system, pressure drop, kPa (in. H_2O)	5.0 (20)	3.6 (14.5)	5.8 (23.5)	6.5 (26)	6.7 (27)	6.5 (26)
Dust inlet, (g/m^3) (gr/dscf)	0.996 (0.4354)	0.574 (0.2508)	0.424 (0.1855)	0.475 (0.2075)	0.231 (0.1008)	0.535 (0.2339)
Dust outlet, g/m^3 (gr/dscf)	0.0487 (0.0213)	0.0522 (0.0228)	0.0502 (0.0220)	0.0524 (0.0229)	0.0508 (0.0222)	0.0636 (0.0278)
Absorber slurry solids concentration, %	2	2	2	2	11	11.8
Absorber pH	4.7	5.7		6.0	6.2	6.2

Table 11. PRELIMINARY TEST DATA, A-SIDE SCRUBBING TRAIN

AUGUST 8 TO 12, 1972

Test number	1	2	3	4	5	6	7	8	9	10
Date	8-8	8-8	8-9	8-9	8-10	8-10	8-11	9-11	8-12	8-12
Gas flow, m^3/sec ($acfm \times 10^3$)	76 (160)	170 (360)	107 (226)	167 (353)	170 (360)	167 (353)	163 (345)	221 (468)	175 (370)	175 (370)
Scrubber system, pressure drop, kPa (in. H_2O)	6.6 (26.5)	6.5 (26.0)	5.2 (21.0)	7.2 (29.0)	7.0 (28.0)	6.7 (27.0)	6.5 (26.0)	7.0 (28.0)	7.0 (28.0)	7.3 (29.5)
SO_2 inlet, ppm	2400	2860	2720	2680	2700	1065	1600	2230	2260	2350
SO_2 outlet, ppm	300	960	495	800	185	63	280	570	520	765
SO_2 removal efficiency, %	87.6	66.4	81.8	70.0	93.2	94.1	82.5	74.4	77.0	67.3
Absorber, pH	5.7	5.9	4.9	5.0	5.5	6.6	6.4			

ciency tests were conducted under full- and partial-load conditions with the upstream ESP in and out of service. Sulfur dioxide removal efficiencies averaged 78.2 percent and 86.8 percent for the A-side and B-side respectively. The average sulfur dioxide inlet loading was 3573 ppm. The A-side value was lower because only one of the two absorber recirculation pumps was in service, resulting in a lower L/G. Slurry carryover in the scrubber resulted in lower particulate removal efficiencies than expected, and this caused high particulate loadings at the scrubber outlet.

SUMMARY OF SYSTEM PERFORMANCE

The performance of the FGD system since start-up is described below on a yearly basis. Details of the 1975, 1976, and 1977 (July), operations are summarized in Table 12.

1972 Operation

The B-side scrubbing train, which included a TCA absorber, was first placed in service February 23, 1972. The A-side came on-line April 7, 1972. To the end of 1972, the A-side was in service a total of 1444 hours and the B-side, 1237 hours. The average annual operability index values for the A- and B-sides were 30 and 25 percent respectively. The longest period of continuous operation was 21 days, achieved by the A-side. Simultaneous operation of the scrubbing trains totalled 469 hours; the longest continuous period was 6 days.

1973 Operation

In April 1973, the utility discontinued operation of the B-side scrubbing train to concentrate on the A-side. The A-side remained in service until November, when it was brought down for repairs and modifications. By this time it had been in service a total of 1726 hours, providing a 23 percent operability index for the year.

Table 12. SUMMARY OF FGD SYSTEM PERFORMANCE, WILL COUNTY FGD SYSTEM: 1975, 1976, AND 1977 (JULY)

Period	Hours	Unit hours	Module	Hours	System performance factors, percent			
					Availability[a]	Operability	Reliability[b]	Utilization[c]
Jan. 75	744	685	A	676	99	99	91	91
Feb. 75	672	666	A	662	99	99	99	99
Mar. 75	744	609	A	605	94	99	86	81
Apr. 75	720	638	A	253	37	40	95	35
May 75	744	744	A	629	84	84	100	84
			B	276	37	37	100	37
June 75	720	642	A	390	64	61	84	54
			B	543	85	85	88	75
July 75	744	689	B	547	79	79	93	74
Aug. 75	744	565	B	568	94	100	82	76
Sept. 75	720	720	B	452	63	63	100	63
Oct. 75[d]	744	195	B	195	32	100	81	26
Nov. 75	720	Scheduled overhaul of boiler, turbine, and scrubbers						
Dec. 75	744	Scheduled overhaul of boiler, turbine, and scrubbers						
Total	8760	6153	A	3123	40	52	38	37
			B	2580	34	42	31	29

(Continued)

Table 12 (Continued).

Period	Hours	Unit hours	Module	Hours	System performance factors, percent			
					Availability[a]	Operability	Reliability[b]	Utilization[c]
Jan. 76	744	Scheduled overhaul of boiler, turbine and scrubbers						
Feb. 76	696	Scheduled overhaul of boiler, turbine and scrubbers						
Mar. 76	744	309	A	140	30	45	62	19
			B	63	9	20	97	8
Apr. 76	720	690	A	138	21	20	83	19
			B	340	51	49	93	47
May 76	744	665	B	567	87	85	88	76
June 76	720	612	A	271	52	44	72	38
			B	517	72	85	83	72
July 76	744	598	A	0	20	0	0	0
			B	538	84	90	84	72
Aug. 76	744	495	A	285	98	57	96	38
			B	304	65	61	54	41
Sept. 76	720	566	A	163	42	29	28	42
			B	431	79	76	74	60
Oct. 76	744	726	A	208	30	29	28	28
			B	408	76	56	70	55
Nov. 76	720	569	A	145	20	26	20	20
			B	394	72	70	66	55
Dec. 76	744	692	A	334	45	48	45	45
			B	357	53	52	51	48
Total	8760	5920	A	1684	27	28	22	19
			B	3919	56	66	50	44

(Continued)

Table 12 (Continued).

Period	Hours	Unit hours	Module	Hours	System performance factors, percent			
					Availability[a]	Operability	Reliability[b]	Utilization[d]
Jan. 77	744	722	A	713	98	99	98	96
			B	8	1	1	1	1
Feb. 77	672	613	A	261	39	42		39
			B	280	42	45		41
Mar. 77	744	727	A	478	97	66		64
			B	550	81	75		73
Apr. 77	720	650	A	441	86	68	81	61
			B	196	45	30	33	21
May 77	744	691	A	15	89	2	16	2
			B	352	98	51	96	47
June 77	720	566	A	76	32	13	13	10
			B	529	93	93	92	73
July 77	744	377	A	201	27	53	27	27
			B	201	70	41	41	21
Total	5080	4347	A	1923	72	44	58	38
			B	2071	67	48	55	41

[a] Availability index: The number of hours the FGD system is available for operation (whether operated or not), divided by the number of hours in the period, expressed as a percentage.

[b] Reliability index: The number of hours the FGD system is in operation for a given period, divided by the number of hours the FGD system is called upon to operate in the period, expressed as a percentage.

[c] Utilization index: The number of hours the FGD system is in operation for a given period, divided by the number of hours in the period, expressed as a percentage

[d] 21-week scheduled turbine, boiler and scrubber outage began Oct. 11.

1974 Operation

The A-side scrubbing train remained in service throughout the year, accumulating 5468 hours of operation. The train was available 6025 hours and the boiler was operational 7924 hours. These figures represent a 69 percent operability and availability index for the year.

1975 Operation

Operations in 1975 commenced in much the same manner as in 1974. The A-side was operational, the B-side still out of service. The A-side remained in service until mid-June, when it was taken out for extensive repairs and modifications. The average operability index for the A-side, through June 20, was 80 percent. The A-side remained out of service throughout the year. Modifications to the B-side (the TCA absorber was converted to a sieve tray unit) were completed and it was returned to service May 20. The B-side operated almost without incident until October 11, when Unit 1 was shut down for a scheduled boiler, turbine, and scrubber overhaul. During the year, the generating unit was in service 6152 hours; the A-side and B-side scrubbing trains were available 3463 and 2969 hours, respectively, and actually operated 3213 and 2580 hours respectively. Based on these service hours, the following index values were calculated for 1975 operations: A-side availability, operability, reliability, and utilization were 40, 52, 38, and 37 percent, respectively; B-side values for the same parameters were 34, 42, 31, and 29 percent respectively. The average sulfur content of the coal burned in Unit 1 during the year was 1.5 percent.

1976 Operation

Unit 1 was returned to service in March following the 4-month overhaul. The A-side and B-side were returned to service March 22 and 29 respectively. During the year, the generating unit was available for service 6450 hours and was operated 5920 hours. The A-side and B-side scrubbing trains were available

2634 and 4883 hours respectively, and were operated 1684 and 3919 hours respectively. Based on these service hours, the following index values were calculated for 1976 operations: the generating unit was 73 percent available; A-side availability, operability, reliability, and utilization were 27, 28, 22, and 19 percent respectively. B-side values for the same parameters were 56, 66, 50, and 44 percent respectively. The average sulfur content of coal burned in Unit 1 during the year was sightly over 1 percent.

1977 Operation

In July 1977, Commonwealth Edison officially concluded the Will County sulfur dioxide scrubbing program. The scrubbers are still in service, removing primarily fly ash and some sulfur dioxide from the flue gas. Low-sulfur western coal is burned. From January to July 1977, several test programs were conducted by the utility, including the evaluation of continuous sulfur dioxide analyzers; high-sulfur coal sludge evaluations; magnesium oxide beneficiation of the limestone slurry; and forced oxidation testing. Virtually all operations were conducted on low-sulfur western coal. During this period, the generating unit was available for service 4394 hours and operated 4347 hours. The A-side and B-side scrubbing trains were available 3689 and 3436 hours respectively, and were operated 1923 and 2071 hours respectively. Based on these service hours, the following index values were calculated for operations from January to July 1977: generating unit availability was 86 percent; A-side availability, operability, reliability, and utilization were 72, 44, 58, and 38 percent respectively; B-side values for the same parameters were 67, 48, 55, and 41 percent respectively.

PROBLEMS, SOLUTIONS, AND SYSTEM MODIFICATIONS

The Will County FGD system has been beset with numerous problems since commercial operation began in February 1972. The major problems, solutions, modifications, and experiments performed on the scrubbing system are described below.

Scrubbing modules

By April 1972, the two scrubbing trains had been placed in the flue gas path: both encountered more problems than had been expected. This resulted in the utility's discontinuing operation of the B-side to concentrate on achieving satisfactory operation of the A-side. By 1974 performance of the A-side had improved to the point where the utility decided to use the B-side again. The B-side was therefore modified to be identical with the A-side. The major change was the removal of the mobile-bed packing in the absorber and its replacement with two stages of sieve trays.

Following completion of conversion to a tray tower, both scrubber-absorber vessels experienced major problems in the form of scale and erosion. Massive gypsum scaling developed in the sump areas of the scrubbing trains. The scale film was reported to be over 1.3 cm (0.5 in.) thick in some places. The scale was removed by shutting the system down and chipping gypsum off the various scrubber internals. Erosion of the scrubber vessel occurred in the horizontal plate above the venturi inlet wash box. A number of holes developed, allowing slurry to seep through and over the outer shell of the venturi. This problem was corrected by fitting each wall wash nozzle with a deflector to redirect the path of the slurry.

Mist eliminators

Fouling and scaling of the mist eliminators in both scrubbing trains has been a persistent problem from the outset of commercial operation. Fouling occurred primarily because of the accumulation of the heavy limestone slurry on the lower sections of the mist eliminators. To rectify this, the wash system was modified so that the nozzles sprayed upward onto the bottom sections of the mist eliminators. Plugging continued to be a problem, however, requiring the addition of extra spray nozzles and the use of a continuous fresh makeup water underspray and an intermittent pond return overspray, which uses a water deluge wash system. The increased amount of fresh makeup water re-

quired, however, upset the system's water balance to the extent that the underspray system had to be modified to an intermittent wash system that alternated on a 5-minutes on/5-minutes off basis.

In May 1975, during the high-sulfur coal burn program, the mist eliminator wash system was again modified. Because use of saturated pond return water caused additional scale development and minor plugging in the mist eliminators, the underspray was converted back to a continuous spray.

Reheaters

The flue gas reheaters have also been the site of numerous problems since initial commercial operation. The major problems included plugging, scaling, stress corrosion cracks in the 304 stainless steel tubes, and eventual failure of the corten tubes. Plugging and scaling in the reheat section are a direct function of the performance of the upstream mist eliminators.

Each bare tube reheater includes a total of nine sections and four sootblowers. The bottom three sections were originally constructed of 304 stainless steel, the top six of corten. These bundles have been replaced by 316L stainless steel tubes in the lower three banks and by carbon steel tubes in the upper six banks. By 1975, six of the 12 new carbon steel bundles had developed peripheral cracks. All of the failures occurred because the tube supports had worked loose, permitting excessive vibration. The coil manufacturer repaired and modified all the tube bundles by redesigning the tube supports and installing an additional support.

Recirculation

The design retention times of the venturi scrubber and absorber recirculation tanks are 4 minutes and 8 minutes respectively. The utility has determined, however, that 50 percent of the flow into the tank system is immediately recycled to the scrubbing system with little or no retention time. Half the

scrubbing solution therefore lacks sufficient time for chemical reactions to be completed before recirculation to the scrubbing system.

Pumps

Three 100 percent capacity venturi recirculation pumps, each rated at 315 l/sec (5000 gal./min), and four 60 percent capacity absorber recirculation pumps, each rated at 331 l/sec (5250 gal./min), were provided for both scrubbing trains. Problems with these pumps have been minimal. One of the absorber recirculation pumps was damaged when a check valve failed in the discharge piping and parts fell into the pump, damaging the impeller and destroying the rubber lining. It was determined that the rubber lining in the check valve had eroded, allowing the base material to corrode and eventually fail. The system supplier reviewed the need for check valves in the pump discharges, recommending that they be removed and the spool pieces relined with rubber.

Sludge treatment

Thickener underflow or retrieved ponded sludge is treated in mixing trucks together with lime and fly ash and hauled to an offsite disposal area. Until September 1975, the treated material was initially disposed of in an on-site, clay-lined disposal basin where the material would set up. Operation of this intermediate hold basin has since been discontinued, and a local firm is now transporting treated sludge from the plant directly to the off-site disposal area.

The utility has purchased a belt-type vacuum filter, which went into service in late 1976. This filter had the advantage of changing the sludge handling method and reducing treatment costs. The additional water recovery, however, has affected the system's water balance, making it more difficult to approach closed loop operations.

ESP

After installation of the FGD system, the upstream ESP was to operate only when the FGD unit was out of service. Nevertheless, it is now operated on a full-time basis. This allows maximum particulate removal and minimizes the amount of fly ash in the scrubbing system, thus alleviating a problem of high solids content in the scrubbing liquor.

Instrumentation

Because of instrument failures and inaccurate readings, pH and sulfur dioxide levels have, for the most part, been measured manually. During the period from January to July 1977, Commonwealth Edison experimented with a number of continuous monitors, including both ERT and Dupont sulfur dioxide analyzers. The utility reported that the Dupont unit performed satisfactorily; it operated with very little maintenance and gave readings verified by grab samples.

Liners

Liners have failed in the duct between the absorber outlet and reheater inlet and in the sump walls of the absorber. In both areas Ceilcote Flakeline 103 coating had been used. The liner flaked, peeled, or was eroded off, and the bare metal surface soon corroded. This problem was corrected in the sump area by applying a coating of Kaocrete refractory over the Flakeline liner.

Chemistry

Process chemistry experimentation and testing focused primarily on pH control, magnesium beneficiation, and forced oxidation. In August 1976, the set point for controlling pH of the scrubbing solution was reduced from 5.4 to 5.1, in an effort to reduce scaling and plugging and to increase reagent utilization. Loss of chemical control and formation of gypsum scale soon resulted in the return to a pH control point of 5.4. In May

1977, a magnesium oxide addition test was conducted. Although sulfur dioxide removal efficiency was increased by approximately 10 percent, neither sludge production rate nor limestone utilization was seriously affected. A forced oxidation test was successfully conducted immediately before termination of sulfur dioxide scrubbing operations. Using liquid oxygen, approximately 5.7 m^3/min. (200 ft^3/min.) of gaseous oxygen was fed into each venturi scrubber downcomer. Oxidation of sulfite to sulfate was increased from 35 to 90 percent.

SYSTEM ECONOMICS

Estimated capital and operating costs for the FGD system at Will County Station are presented in Tables 13 and 14 and in Appendix A. It should be pointed out that this system is a full-size, prototype demonstration unit, erected under an accelerated overtime schedule and backfitted on a unit with little available space. The cost per kilowatt is based on a 137-MW net unit rating with the FGD system in operation.

FUTURE OPERATION

As indicated previously, sulfur dioxide removal operations at Will County were concluded in July 1977. Particulate removal operations are continuing at the facility. Some sulfur dioxide removal from low-sulfur western coal flue gas is occurring because of the alkalinity of the scrubbing solution; this is due to limestone addition for pH control. Actual sulfur dioxide removal efficiencies have not yet been determined. During the more than 5 years that sulfur dioxide removal operations were conducted at the plant, a vast amount of information was accumulated on the design and operation of FGD systems. This information is being used for the design, installation, and future operation of a full-scale, limestone-based FGD system now under construction at the utility's Powerton Station, Unit 5, Boiler 51. This system, unlike the Will County system, is not designed for test

Table 13. ESTIMATED CAPITAL INVESTMENT COSTS OF WILL COUNTY UNIT 1 FGD SYSTEM

Gas cleaning system	Direct cost	Indirect cost	Total cost
B&W venturi/absorber	$ 2,928,000		
Equipment erection	5,556,000		
Electrical equipment and erection	1,210,000		
Foundations	923,000		
Limestone handling system	204,000		
Professional engineering	965,000		
Mill and SO_2 buildings	193,000		
Structural steel	375,000		
Miscellaneous equipment	946,000		
	$13,300,000	$ 1,600,000	$14,900,000
Sludge treatment	573,000	69,000	642,000
Total	$13,873,000	$ 1,669,000	$15,542,000
$/kW (net)	101	12	113

Table 14. APPROXIMATE 1975 COST TO OWN AND OPERATE WILL COUNTY UNIT 1 WET SCRUBBER

Scrubber system	$ Annual Cost	$/Mg of coal $/Ton of coal	¢/GH ¢/Million Btu	Mills/kWh
Carrying charges on $14,900,000	2,280,000	13.82 (12.54)	64.89 (65.3)	7.47
Labor (operating and technical)	81,709	0.50 (0.45)	2.18 (2.3)	0.27
Maintenance (labor and material)	256,656	1.55 (1.41)	7.01 (7.4)	0.84
Limestone	62,726	.37 (0.34)	1.71 (1.8)	0.21
Auxiliary power	586,875	3.56 (3.23)	15.92 (16.8)	1.92
Reheat steam	72,595	.44 (0.40)	1.99 (2.1)	0.24
	3,340,561	20.24 (18.37)	90.70 (95.7	10.95
Sludge treatment				
Carrying charges on $642,000	98,000	0.60 (0.54)	2.65 (2.8)	0.32
Sludge treatment	546,217	3.31 (3.00)	14.88 15.7	1.79
	644,217	3.91 (3.54)	17.53 (18.5)	2.11
Scrubber and sludge treatment total cost				
	3,984,778	24.15 (21.91)	108.23 (114.2	13.06

Notes:

1. Scrubber system has a 14-year life.
2. Sludge treatment cost includes hauling to an off-site disposal area.
3. A-module on line 3213 hours, B-module on line 2580 hours. 165 Gg (181,886 ton) of coal consumed, 3.68 PJ (3.45×10^{12} Btu) and 305.1×10^{6} net kWh are proportioned to scrubber on-line hours.
4. Coal average: 22.3 MJ/kg (9604 Btu/lb) 1.5% sulfur.
5. Unit 1 12-month capacity factor for 1975 was 49.4%.

purposes, but for compliance with emission regulations. Table 15 summarizes the Powerton No. 51 FGD system.

Table 15. SUMMARY OF FGD DATA, POWERTON STATION UNIT 5, BOILER 51

FGD unit capacity, MW	450
Design coal specifications:	
Heat content, MJ/kg (Btu/lb)	24.4 (10,500)(avg.)
Sulfur, percent	3.6 (avg.), 6.0 (max.)
Ash, percent	8.3 (avg.), 16.0 (max.)
Chloride, percent	0.2 (max.)
Moisture, percent	17.3 (avg.)
Application (new/retrofit)	Retrofit
Process	Limestone
Supplier	Universal Oil Products
Absorber type	Turbulent contact absorber
Number of modules	3
Exit flue gas capacity m^3/sec (acfm)	735 (1,556,217)
Exit flue gas termperature, °C (°F)	53 (128)
Design removal efficiency:	
Particulate, percent	N/A[a]
Sulfur dioxide, percent	84[b]
L/G ratio, l/sec @ °C (gal./1000 acf @ °F)	8 @ 53°C (60@ 128)
Gas reheat ΔT, °C (°F)	14 (25)
Sludge disposal	Stabilized sludge disposed of on plant grounds in a lined pond 1.2 km (0.75 miles) from generating unit.
SO_2 emission regulation ng/J (lb/million Btu)	774 (1.8)
Gas bypass capability	Yes
FGD schedule milestones:	
Contract awarded	February 1976
Start of construction	March 1977
Initial operation	Late 1978
Commercial operation	December 1979
FGD Economics:	
Capital cost, $/kW	117.65
Operating cost, mills/kWh	8.70c

[a] N/A - not applicable: ESP upstream of FGD system provides control of particulate matter.

[b] This is the maximum removal efficiency value based upon 100 percent conversion of 6 percent sulfur coal with a 24.4 MJ/kg (10,500 Btu/lb) heating value.

[c] Estimated value, which includes the following: 2.7 mills/kWh for operation and maintenance; 6.0 mills/kWh for auxiliary power requirements; FGD life span of 30 years.

APPENDIX A

PLANT SURVEY FORM

A. Company and Plant Information

1. Company name: Commonwealth Edison Company
2. Main office: P.O. Box 767, Chicago, Illinois 60690
3. Plant name: Will County Station
4. Plant location: Romeoville, Illinois
5. Responsible officer: Mr. J. P. McCluskey
6. Plant manager: James R. Gilbert
7. Plant contact: R. Kunshek
8. Position: Director - Environmental Affairs Dept.
9. Telephone number: (312) 294-2906
10. Date information gathered: 6/22/76 and 6/1/77

Participants in meeting	Affiliation
G. A. Isaacs	PEDCo Environmental, Inc.
B. A. Laseke	PEDCo Environmental, Inc.
T. C. Ponder	PEDCo Environmental, Inc.
R. Klier	PEDCo Environmental, Inc.
H. M. Drake	PEDCo Environmental, Inc.
B. Mansfield	Commonwealth-Edison
M. Poole	Commonwealth-Edison

B. Plant and Site Data

1. UTM coordinates: _____

2. Sea Level elevation: Sea level

3. Plant site plot plant (Yes, No): No
(include drawing or aerial overviews)

4. FGD system plan (Yes, No): See diagram

5. General description of plant environs: A highly industrialized area - many refineries and chemical plants

6. Coal shipment mode: Two types of coal were burned during the course of the SO_2 scrubbing program, both shipped in by barge. The western, low-sulfur coal, which is the only coal burned in the boiler after the SO_2 program was completed, is shipped to Havana, Illinois, from southern Montana via rail, unloaded, and barged upriver.

C. FGD Vendor/Designer Background

1. Process name: Wet Limestone Scrubbing

2. Developer/licensor name: Babcock & Wilcox

3. Address: Power Generation Group, 20 S. Van Buren Avenue, Barberton, Ohio

4. Company offering process:

Company name: Babcock & Wilcox

Address: 20 S. Van Buren Avenue

Location: Barberton, Ohio

Company contact: Jack F. Stewart

Position: Sales Manager

Telephone number: (216) 753-4511

5. Architectural/engineers name: Bechtel Power Corp.

Address: 50 Beale Street

Location: San Francisco, California

Company contact: Mr. J. J. Smortchevsky

Position: Project Engineer

Telephone number: (415) 764-6262

D. Boiler Data

1. Boiler: Unit 1
2. Boiler manufacturer: Babcock & Wilcox
3. Boiler service (base, standby, floating, peak):

   Cycling load service
4. Year boiler placed in service: 1955
5. Total hours operation: (1976) 5,920
6. Remaining life of unit:
7. Boiler type: Radiant cyclone boiler
8. Served by stack no.: One
9. Stack height: 107 m (350 ft)
10. Stack top inner diameter: 3.8 m (12.4 ft)
11. Unit ratings:

    Gross unit rating: 167 MW

    Net unit rating without FGD: 144 MW

Net unit rating with FGD: 137 MW (4% of gross for FGD)

Name plate rating: 177 MW

12. Unit heat rate: 11.8 MJ/net kWh (11,217 Btu/net kWh)

Heat rate without FGD: 11.8 MJ/net kWh (11,217 Btu/net kWh)

Heat rate with FGD: 4 % energy penalty

13. Boiler capacity factor, (1975): 49.5%

14. Fuel type (coal or oil): Coal

15. Flue gas flow:

Maximum: 363 m^3/s (770,000 acfm)

Temperature: 179°C (355°F)

16. Total excess air: 4% O_2 in flue gas stream

17. Boiler efficiency:

E. Coal Data (See General Comments, Section M, item 1)

1. Coal supplier:

Name: Decker Coal Company

Location: Montana

Mine location: Dietz No. 1

County, State: Montana (southern portion)

Seam: No. 1

2. Gross heating value: 21.2-22.3 MJ/kg (9100-9600 Btu/lb)

3. Ash (dry basis): 3.0 - 6.0 %

4. Sulfur (dry basis): 0.3 - 0.6 %

5. Total moisture: 22.0 - 25.0 %

6. Chloride: Not available

7. Ash composition (See Table A1) Not available

Table A1

Constituent	Percent weight
Silica, SiO_2	Not Available
Alumina, Al_2O_3	
Titania, TiO_2	
Ferric oxide, Fe_2O_3	
Calcium oxide, CaO	
Magnesium oxide, MgO	
Sodium oxide, Na_2O	
Potassium oxide, K_2O	
Phosphorous pentoxide, P_2O_5	
Sulfur trioxide, SO_3	
Other	
Undetermined	

F. Atmospheric Emission Regulations (weight per unit heat input)

1. Applicable particulate emission regulation

a) Current requirement: 86 ng/J (0.2 lb/10^6 BTU)

AQCR priority classification: _____

Regulation and section No.: IPCB 203 (g)(1)(C)

b) Future requirement (Date:): _____

Regulation and section No.: _____

2. Applicable SO_2 emission regulation

a) Current requirement: 774 ng/J (1.8 lb/10^6 BTU)

AQCR Priority Classification: _____

Regulation and section No.: IPCB 204 (C)(1)(A)*

b) Future requirement (Date:) _____

* See note in Section 2.

Regulation and section No.: _____

G. Chemical Additives: (Includes all reagent additives - absorbents, precipitants, flocculants, coagulants, pH adjusters, fixatives, catalysts, etc.)

1. Trade name: Limestone

   Principal ingredient: $CaCO_3$ = 97.5%; $MgCO_3$ = 0.99%

   Function: SO_2 absorbent

   Source/manufacturer: Columbia

   Quantity employed: 3 kg/sec (12 tons/hour)

   Point of addition: Absorber recirculation tank

2. Trade name: Lime

   Principal ingredient: CaO

   Function: Sludge stabilizer

   Source/manufacturer: Columbia

   Quantity employed: 10 g/kg (200 lb/ton) of sludge (dry)

   Point of addition: Concrete mixing trucks

3. Trade name: Collected coal fly ash

   Principal ingredient: Fly ash

   Function: Sludge stabilizer

   Source/manufacturer: Collected from other operating units on plant premises.

   Quantity employed: 200 g/kg (400 lb/ton) of sludge (dry)

   Point of addition: Concrete mixing trucks

4. Trade name: N/A*

   Principal ingredient: _____

   Function: _____

   Source/manufacturer: _____

   Quantity employed: _____

* Not applicable

Point of addition: _____

5. Trade name: N/A

Principal ingredient: _____

Function: _____

Source/manufacturer: _____

Quantity employed: _____

Point of addition: _____

H. Equipment Specifications

1. Electrostatic precipitator(s)

Number: One

Manufacturer: Joy Manufacturing/Western Precip. Div.

Particulate removal efficiency: 90% design, 79% actual

Outlet temperature: 168°C (355°F)

Pressure drop: _____

2. Mechanical collector(s) N/A

Number: _____

Type: _____

Size: _____

Manufacturer: _____

Particulate removal efficiency: _____

Pressure drop: _____

3. Particulate scrubber(s)

Number: Two (A and B trains)

Type: Adjustable-throat venturi

Manufacturer: Babcock & Wilcox

Dimensions: 2.4 x 7.9 x 4.9 m (8 x 26 x 16 ft)

Material, shell: Carbon steel

Material, shell lining: Plasite and Kaocrete

Material, internals: N/A

No. of modules: One per train

No. of stages: One per module

Nozzle type: Stainless steel

Nozzle size:

No. of nozzles: 48 venturi, 32 wall wash

Boiler load: 50%

Scrubber gas flow: 182 m^3/sec, 179°C (335,000 acfm, 355°F)

Liquid recirculation rate: 366 l/sec (5800 gal./min)

Modulation:

L/G ratio: 2.4 l/m^3 (18 gal./1000 acf)

Scrubber pressure drop: 2240 Pa (9 in. H_2O)

Modulation:

Superficial gas velocity: 36.6 m/sec (120 ft/sec)

Particulate removal efficiency: 98% (design)

Inlet loading: 366 mg/m^3 (0.16 gr/scf)*

Outlet loading: 92 mg/m^3 (0.04 gr/scf)*

SO_2 removal efficiency:

Inlet concentration:

Outlet concentration:

4. SO_2 absorber(s)

Number: Two (A and B trains)

Type: Countercurrent tray tower, two stage

Manufacturer: Babcock & Wilcox

* Based on tests conducted June 3-4, 1975, using high-sulfur Illinois coal (3.98% sulfur).

Dimensions: 4.9 x 7.3 x 18.3 m (16 x 25 x 60 ft)

Material, shell: Corten steel

Material, shell lining: Rubber

Material, internals: Two perforated trays

No. of modules: One per train

No. of stages: Two

Packing type: N/A

Packing thickness/stage: N/A

Nozzle type: Stainless steel

Nozzle size:

No. of nozzles:

Boiler load: 50%

Absorber gas flow: 149 m^3/sec, (315,000 acfm, 128°F)

Liquid recirculation rate: 694 l/sec (11,000 gal./min)

Modulation:

L/G ratio:

Absorber pressure drop:

Modulation:

Superficial gas velocity: 3.0 m/s (9 ft/s)

Particulate removal efficiency:

Inlet loading:

Outlet loading: 92 mg/m^3 (0.04 gr/scf)

SO_2 removal efficiency: 76% (design)

Inlet concentration:

Outlet concentration:

5. Clear water tray(s)

Number: N/A

Type: _____

Materials of construction: _____

L/G ratio: _____

Source of water: _____

6. Mist eliminator(s)

Number: Two (A and B trains)

Type: Chevron

Materials of construction: FRP (Hetron)

Manufacturer: Babcock & Wilcox

Configuration (horizontal/vertical): Horizontal

Distance between scrubber bed and mist eliminator:

3.05 m (10 ft)

Mist eliminator depth: _____

Vane spacing: 3.8 cm (1.5 in)

Vane angles: 45°

Type and location of wash system: Continuous fresh water underspray; deluge pond water overspray

Superficial gas velocity: _____

Pressure drop: 0.50 kPa (1.0 in. H_2O)

Comments: Each mist eliminator is a 2-stage, 3-pass, Z-shape, 90°, sharp-angle bend unit; 1.2 m (4 ft) between stages;

7. Reheater(s): Two (A and B trains)

Type (check appropriate category):

- [X] in-line
- [ ] indirect hot air
- [ ] direct combustion
- [ ] bypass
- [ ] exit gas recirculation
- [ ] waste heat recovery
- [ ] other

Gas conditions for reheat:

Flow rate: 180 m^3/sec (380,000 acfm)

Temperature: 53°C (128°F)

SO_2 concentration: Low and high-sulfur coal

Heating medium: Saturated steam

Combustion fuel: N/A

Percent of gas bypassed for reheat: N/A

Temperature boost (ΔT): 11°C (52°F)

Energy required: 3.2% of boiler input

Comments: Reheat steam pressure is 2515 kPa (350 psig), steam temperature is 224°C (435°F), consumption is 5.7 kg/sec (45,000 lb/hr).

8. Fan(s) (Two, 1 per scrubbing train)

Type: Induced-draft boiler booster fan

Materials of construction:

Manufacturer:

Location: Suction side of existing boiler I.D. fan

Fan/motor speed:

Motor/brake power: 1680 W (2250 hp)

Variable speed drive: _____

9. Tank(s)

Item	Venturi scrubber recirculation tank	SO_2 absorber tower recirculation tank	Limestone slurry makeup tank
Total number of tanks	2	2	1
Retention time at full load	Variable	Variable	4 hr
Temperature, °C (°F)	53 (128)	53 (128)	Ambient
pH	5.1-5.7	5.8	7.0
Solids content, percent	8	8	15-30
Specific gravity	1.102	1.049	
Material of construction	Rubber-lined carbon steel	Rubber-lined carbon steel	Carbon steel

10. Recirculation/slurry pump(s)

Description	Manufacturer	Materials	No.	Capacity	Service
Venturi Recir.	A-S-H	Rubber-lined	3	366 l/sec (5800 gpm)	100% capacity 2 oper./1 spare
Absorber Recir.	A-S-H	Rubber-lined	4	353 l/sec (5600 gpm)	60% capacity No spare
Mill Prod. Pumps	A-S-H	Rubber-lined	4	32 l/sec (500 gpm)	100% capacity 1 oper./1 spare
Slurry Transfer	A-S-H	Rubber-lined	2	20 l/sec (312 gpm)	100% capacity 1 oper./1 spare

11. Thickener(s)/clarifier(s)

Number: One

Type: Thickener

Manufacturer: _____

Materials of construction: _____

Configuration: Circular, sloped bottom

Diameter: 19.8 m (65 ft)

Depth: 4.6 m (15 ft)

Rake speed: _____

12. Vacuum filter(s)

Number: One

Type: Belt-type vacuum filter

Manufacturer: _____

Materials of construction: _____

Belt cloth material: _____

Design capacity: 0.94 kg/sec (90 ton/day)

Filter area: _____

13. Centrifuge(s)

Number: Not applicable

Type: _____

Manufacturer: _____

Materials of construction: _____

Size/dimensions: _____

Capacity: _____

14. Interim sludge pond(s) N/A (See Section M - Comments, Item 2)

Number: _____

Description: _____

Area: _____

Depth: _____

Liner type: _____

Location: _____

Typical operating schedule: _____

_____

Ground water/surface water monitors: _____

_____

15. Final disposal site(s) N/A (See Section M - Comments, Item 2)

Number: _____

Description: _____

Area: _____

Depth: _____

Location: _____

Transportation mode: _____

Typical operating schedule: _____

_____

16. Raw materials production

Type: Wet ball mills

Number: Two

Manufacturer: _____

Capacity: 3 kg/sec (12 ton/hr)

Product characteristics: Mill product mesh size is 95% < 325 mesh

_____

I. Equipment Operation, Maintenance, and Overhaul Schedule

1. Scrubber(s)

Design life: _____

Elapsed operation time: _____

Cleanout method: _____

Cleanout frequency: _____

Cleanout duration: _____

Other preventive maintenance procedures: _____

_____

2. Absorber(s)

Design life:_____

Elapsed operation time:_____

Cleanout method:_____

Cleanout frequency:_____

Cleanout duration:_____

Other preventive maintenance procedures:_____

_____

3. Reheater(s)

Design life:_____

Elapsed operation time:_____

Cleanout method:_____

Cleanout frequency:_____

Cleanout duration:_____

Other preventive maintenance procedures:_____

_____

4. Scrubber fan(s)

Design life:_____

Elapsed operation time:_____

Cleanout method:_____

Cleanout frequency:_____

Cleanout duration:_____

Other preventive maintenance procedures:_____

_____

5. Mist eliminator(s)

Design life:_____

Elapsed operation time:_____

Cleanout method: _____

Cleanout frequency: _____

Cleanout duration: _____

Other preventive maintenance procedures: _____

_____

6. Pump(s)

Design life: _____

Elapsed operation time: _____

Cleanout method: _____

Cleanout frequency: _____

Cleanout duration: _____

Other preventive maintenance procedures: _____

_____

7. Vacuum filter(s)/centrifuge(s)

Design life: _____

Elapsed operation time: _____

Cleanout method: _____

Cleanout frequency: _____

Cleanout duration: _____

Other preventive maintenance procedures: _____

_____

8. Sludge disposal pond(s)

Design life: _____

Elapsed operation time: _____

Capacity consumed: _____

Remaining capacity: _____

Cleanout procedures: _____

_____

J. Cost Data

1. Total installed capital cost: $15,538,000

2. Annualized operating cost: $3,984,778

3. Cost analysis (see breakdown: Table A2)

4. Unit costs

   a. Electricity: $586,875 (1.92 mills/kWh)

   b. Water: _____

   c. Steam: $72,595 (0.24 mills/kWh)

   d. Fuel (reheating/FGD process): N/A

   e. Fixation cost: $546,217

   f. Raw material: $62,726 (0.21 mills/kWh) limestone

   g. Labor: $81,709 (0.27 mills/kWh) for operating and technical labor; maintenance labor not included

5. Comments: Will County FGD system is a full-scale demonstration unit erected on an accelerated overtime schedule in a difficult retrofit application. The capital cost figure reflects these constraints. The annualized operating cost figure is provided for 1975 operations.

Table A2. Cost Breakdown

Cost elements	Included in cost estimate		Estimated amount or % of total capital cost		
	Yes	No	Breakdown $		
			Direct	Indirect	Total
A. Capital Costs					
Scrubber modules	X		2,928,000		2,928,000
Reagent separation facilities	X		397,000		397,000
Waste treatment and disposal pond	X				642,000
Byproduct handling and storage					
Site improvements	X		In contractors fee		
Land, roads, tracks, substation	X		In contractors fee		
Engineering costs	X		965,000		965,000
Contractors fee	X		9,010,000		9,010,000
Interest on capital during construction			13,300,000	1,600,000*	14,900,000
					15,542,000
B. Annualized Operating Cost					
Fixed Costs					
Interest on capital	X		2,280,000	98,000	2,378,000
Depreciation					
Insurance and taxes					
Labor cost including overhead	X		81,709		81,709
Variable costs					
Raw material	X		62,726		62,726
Utilities	X		586,875	72,595	659,470
Maintenance	X		256,656		256,656
Sludge Treatment			546,217		546,217
					3,984,778

* 12% of direct

K. Instrumentation

A brief description of the control mechanism or method of measurement for each of the following process parameters:

- Reagent addition: See remarks (below)

- Liquor solids content: See remarks (below)

- Liquor dissolved solids content: See remarks (below)

- Liquor ion concentrations See remarks (below)

  Chloride: _____

  Calcium: _____

  Magnesium: _____

  Sodium: _____

  Sulfite: _____

  Sulfate: _____

  Carbonate: _____

  Other (specify): _____

- Liquor alkalinity: See remarks (below)
- Liquor pH: See remarks (below)
- Liquor flow: See remarks (below)
- Pollutant (SO_2, particulate, NO_x) concentration in flue gas: See remarks (below)
- Gas flow: See remarks (below)
- Waste water See remarks (below)
- Waste solids: See remarks

Provide a diagram or drawing of the scrubber/absorber train that illustrates the function and location of the components of the scrubber/absorber control system.

Remarks: Text of report provides a diagram (Figure 4) and description of the scrubber/absorber control system.

L. Discussion of Major Problem Areas:

1. Corrosion: See text of report (Section 4 - Problems, Solutions, and System Modifications)

2. Erosion: See text of report (Section 4 - Problems, Solutions, and System Modifications)

3. Scaling: See text of report (Section 4 - Problems, Sclutions, and System Modifications)

4. Plugging: See text of report (Section 4 - Problems, Solutions, and System Modifications)

5. Design problems: See text of report (Section 4 - Problems, Solutions, and System Modifications)

6. Waste water/solids disposal: See text of report (Section 4 - Problems, Solutions, and System Modifications)

7. Mechanical problems: See text of report (Section 4 - Problems, Solutions, and System Modifications)

M. General comments:

1. Initial scrubbing operations were conducted on high-sulfur Illinois coal. A long-term contract for low-sulfur western coal was made in 1975. Thereafter, scrubbing operations were conducted on high-sulfur coal, low-sulfur coal and blends of both. Operation on low-sulfur coal only began in July 1977.

2. A 0.03 km^2 (7-acre) on-site clay-lined hold basin was used for temporary sludge disposal prior to September 1975. The thickener underflow is treated with fly ash and lime and transported directly to an off-site landfill. During overflow or equipment emergencies, the thickener is bypassed and wastes are disposed in the interim pond. This material is retrieved, treated, and hauled away to the off-site landfill during later reduced-load periods.